Chirripo Resources Inc.

Annual Report 2003

Bear Canyon, Alberta

Company Profile

Chirripo Resources Inc. is an emerging junior oil and gas company that trades on the TSX Venture Exchange under the symbol "CHO". The Company's headquarters are in Calgary, Alberta.

Chirripo Resources Inc. was incorporated in March 1997 as a junior capital pool company and completed its major transaction in January 1999 by acquiring Chirripo Oil and Gas Ltd.

The Company has grown by using a balanced investment approach through strategic property acquisitions, which compliment the Company's operational expertise and low-risk exploitation projects that generate near term cash flow.

As an emerging full cycle oil and gas company, Chirripo is acquiring larger controlling interests in its focus areas as it strives to lower operating, finding and onstream costs. With a strong balance sheet and a large undeveloped land base, Chirripo is strategically positioned to participate in high reward exploration projects.

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Annual Meeting

Shareholders are invited to attend the Company's annual meeting, to be held at the Rideau Room, The Calgary Westin, 320 – 4th Avenue S.W., Calgary, AB, on Wednesday, May 12, 2004 at 3:00 pm. Shareholders unable to attend the meeting are requested to complete and return the Proxy Form at their earliest convenience to Computershare Trust Company of Canada.

Dear Shareholders:

2003 was highlighted by continued production growth in each of the Company's two core areas and the development of new exploratory projects that will have the potential to add significant reserve growth in 2004 and 2005. All of the new exploration prospects are located in the deeper part of the Western Canadian Sedimentary Basin where reserves are characterized by multi-zone potential and a longer reserve life.

To support the continued development of Chirripo's reserve base and maintain an inventory of new prospects, the Company spent 28% of its 2004 capital budget acquiring seismic and undeveloped land. The Company bought 39 miles of 2D seismic in its Peace River Arch core area over undeveloped land at Tangent, Iroquois and Bear Canyon. The Company also purchased 10 square miles of 3D seismic over its Keg River Basin properties of Amigo, Black and Zama. Chirripo continued to increase its undeveloped land position from 19,800 net acres in 2002 to 27,200 net acres by the end of 2003, adding 7,400 net acres including a new property with low-risk development potential at Giroux Lake. By acquiring the new land and seismic data in 2003, Chirripo has established a strong foundation for continued growth in 2004 and 2005.

Through a combination of low-risk exploitation and focused acquisitions, the Company more than offset declines by increasing its year-over-year average production rate 56% from 145 boe/d in 2002 to 226 boe/d in 2003. Despite very strong commodity prices in 2003 Chirripo closed three separate acquisitions that added net production of 34 boe/d and 176 Mboe of proven plus probable reserves for a net cost of $562,000. In addition, the following development activities added 76 boe/d in 2003:

- recompleted one well (1.00 net) at Bear Canyon, two wells (0.55 net) at Zama, one well (0.32 net) at Shekilie and reactivated one well (1.00 net) at Amigo;
- installation of plunger lift at Rigel East and Bellshill Lake and adding compression at Gordondale;
- drilled one well (0.25 net) at Bear Canyon that was dry and abandoned and participated in four oil wells (0.04 net) at Saddle Hills.

The Company farmed-out its non-core property in Fenn Big Valley in November 2003. The farmee has shot both 2D and 3D seismic on two sections of land and has licensed a Leduc well with an anticipated spud date of May 2004. Chirripo will retain a sliding scale royalty of 5% - 15% on oil and 15% on gas from revenues generated for the duration of the agreement.

Chirripo's financial performance for 2003 reflects the operational success and the growing maturity of its business plan. Investor confidence in Chirripo's balanced investment approach was illustrated by closing a brokered private placement, fully subscribed, for gross proceeds of $1.05 million on January 29, 2004. With the required funding in place, Chirripo was able to execute a higher risk/reward winter capital program that resulted in a significant oil find at Amigo and a successful gas well at Greencourt. Both wells have been completed and tested with the Greencourt well tied-in before breakup and the Amigo well to be tied-in following breakup in June. The Company expects the two wells combined production will add 250 boe/d by the third quarter 2004.

Our challenge remains one of growing production and reserves in a highly competitive industry. Through a combination of rigorous technical evaluation of exploration and development projects and its expanded land and prospects inventory, Chirripo has positioned itself to meet tomorrow's challenges and grow in the years ahead.

On behalf of the board, I would like to express my thanks for the continued support of our investors and the dedication and commitment our team of professionals have shown towards executing the Company's business objectives.

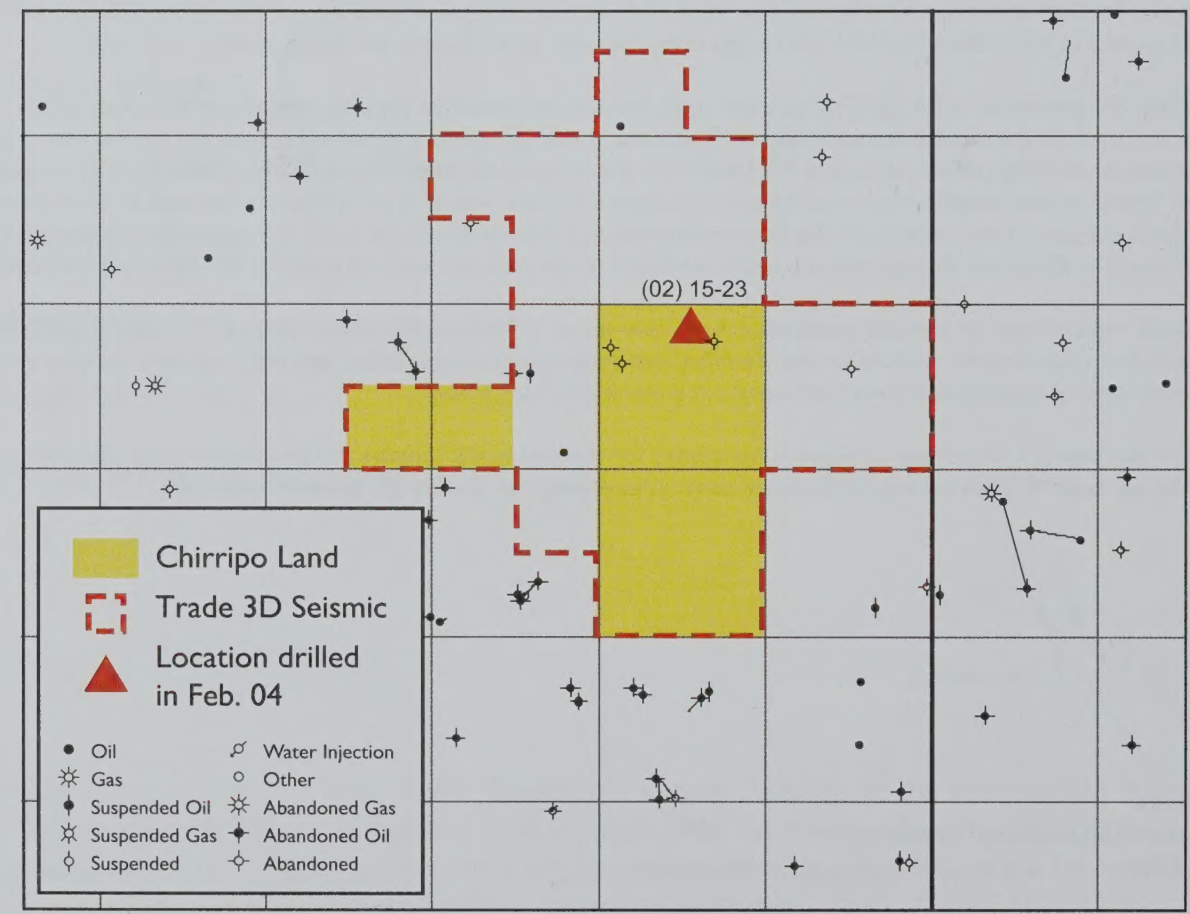
Sincerely,

Issa Abu-Zahra
President and Chief Executive Officer
March 24, 2004

Operations Review

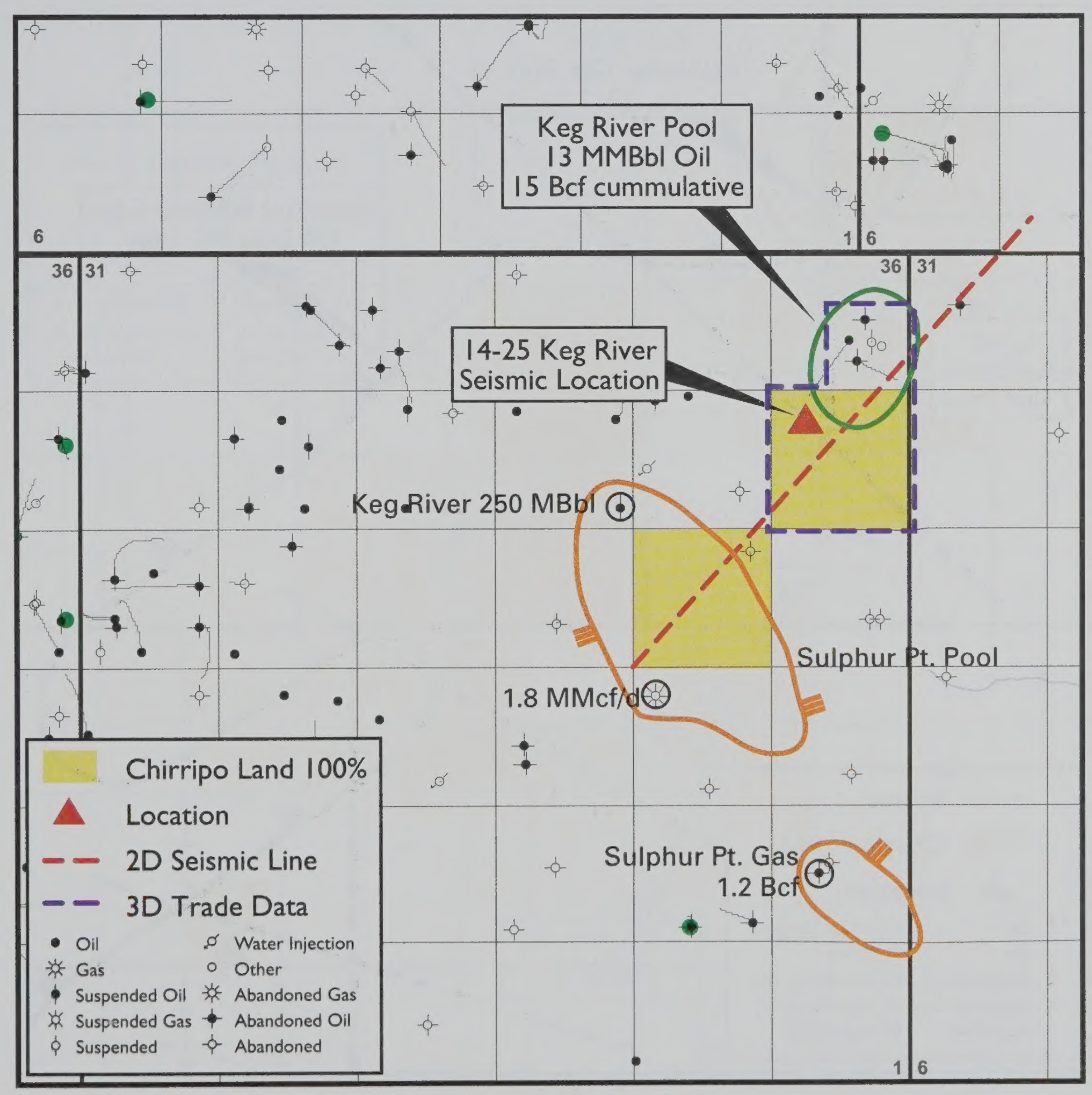
Keg River Basins - Development
Zama Area, Alberta

The Company has three sections of 100% lands that are situated in the Zama Basin dominated by pinnacle reef development composed of stromatopoids and lime sands in the Devonian Keg River and hydocarbons trapped within the Sulphur Point formation as a result of differential compaction over the pre-existing reefs. Chirripo purchased six square miles of 3D seismic in December 2003 to further evaluate its prospect in section 23. In February 2004, a well was drilled to its target depth of 1,547 meters, encountering both a Sulphur Point gas zone, which was drill stem tested at a flow rate of 1.1 mmcf per day and a Keg River oil zone, which was briefly flow tested during completion. The Keg River oil zone tested at a restricted rate of 260 bbls and 200 mcf of solution gas per day through a 3/16-inch choke at a flowing wellhead pressure of 400 psi. No appreciable amount of formation water was produced. Due to Alberta Energy and Utility Board requirements regarding solution gas conservation, the well will remain suspended until a pipeline is constructed in June. The pipeline route has been surveyed and the required notifications are in progress. Chirripo has a 100 percent working interest in this well and is expecting production to commence by the third quarter of 2004.



Keg River Basins - Exploration
Black Area, Alberta

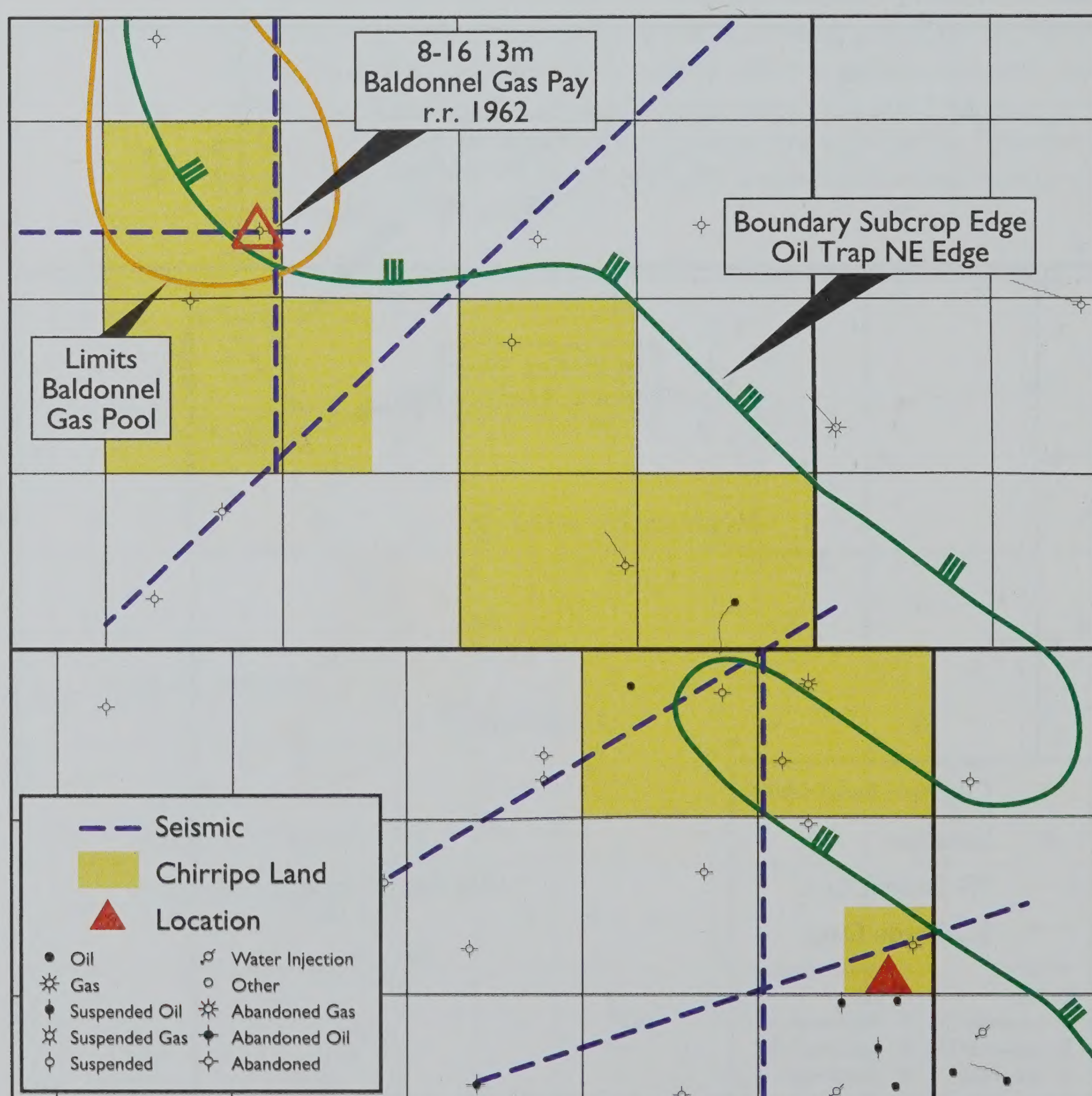
The Company has 100% in two sections of undeveloped land adjacent to the prolific Keg River "T" pool that has cummulative production of 15 Bcf of gas and 13 MMbbl of oil. Situated in the heart of the Rainbow Basin, Black is a high risk/high reward opportunity dominated by pinnacle reef development and both Sulphur Point and Slave Point drapes. Recently purchased 2D and 3D seismic has identified a location at 14-25 based on these drapes with a reserve potential of 1 MMbbl of oil in place. The Company is actively seeking partners to share the risk and plans to drill one well by December 2004.



Peace River Arch - Development

Bear Canyon Area, Alberta

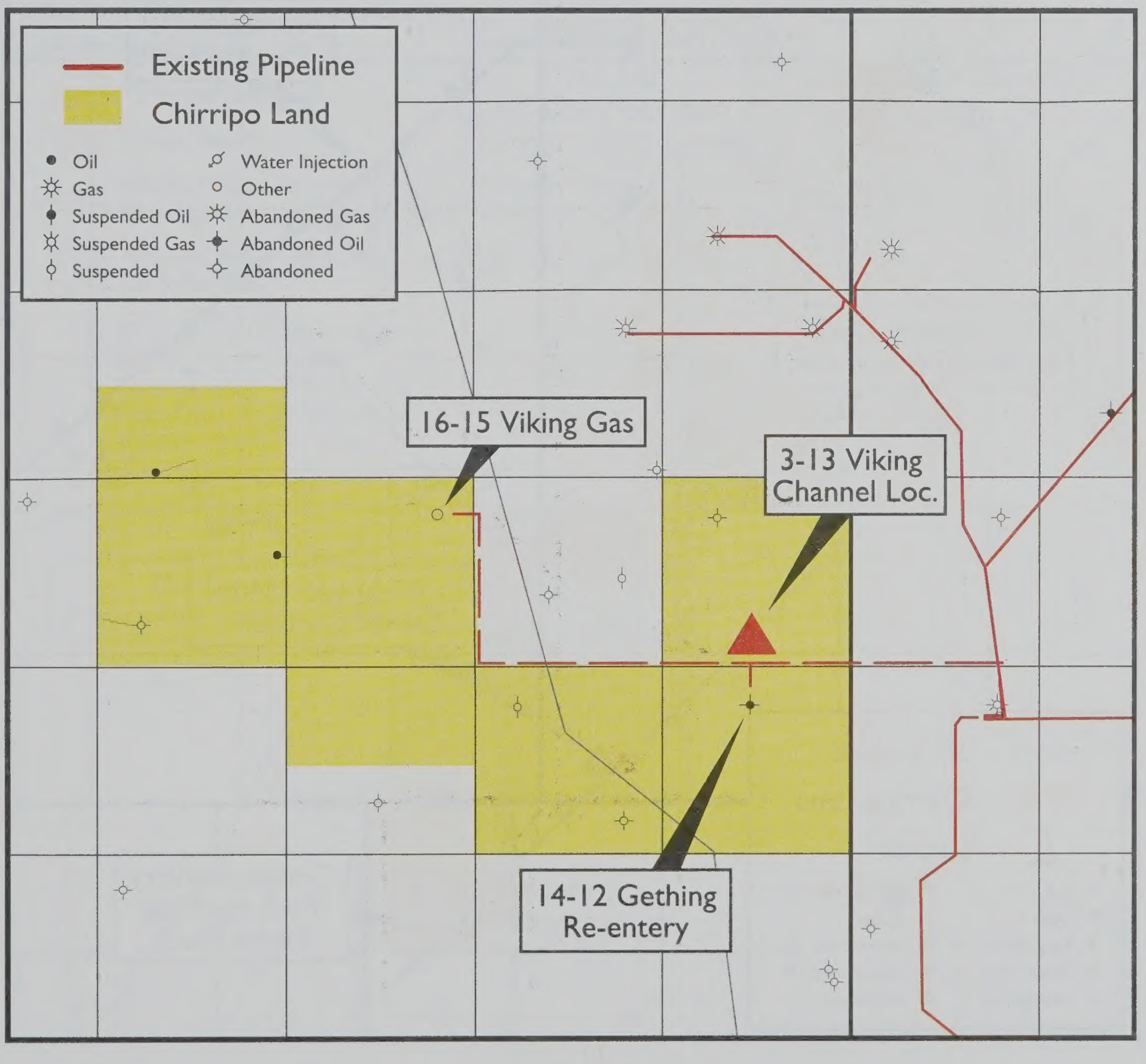
The Company has 7.75 sections of undeveloped 100% WI lands along the Boundary Lake subcrop NE edge located north of the Bonanza pool in north central Alberta. The company recompleted one well in the Boundary Lake earlier in 2003 with marginal success producing 6 bbl/d before freezing up in January 2004. The Company drilled one well with a working interest of 25% in December 2004 that was dry and abandoned. The Company has interpreted 20 miles of 2D seismic and has identified a Baldonnel gas play that Chirripo will pursue further in 2004.



Peace River Arch - Development

Giroux Lake Area, Alberta

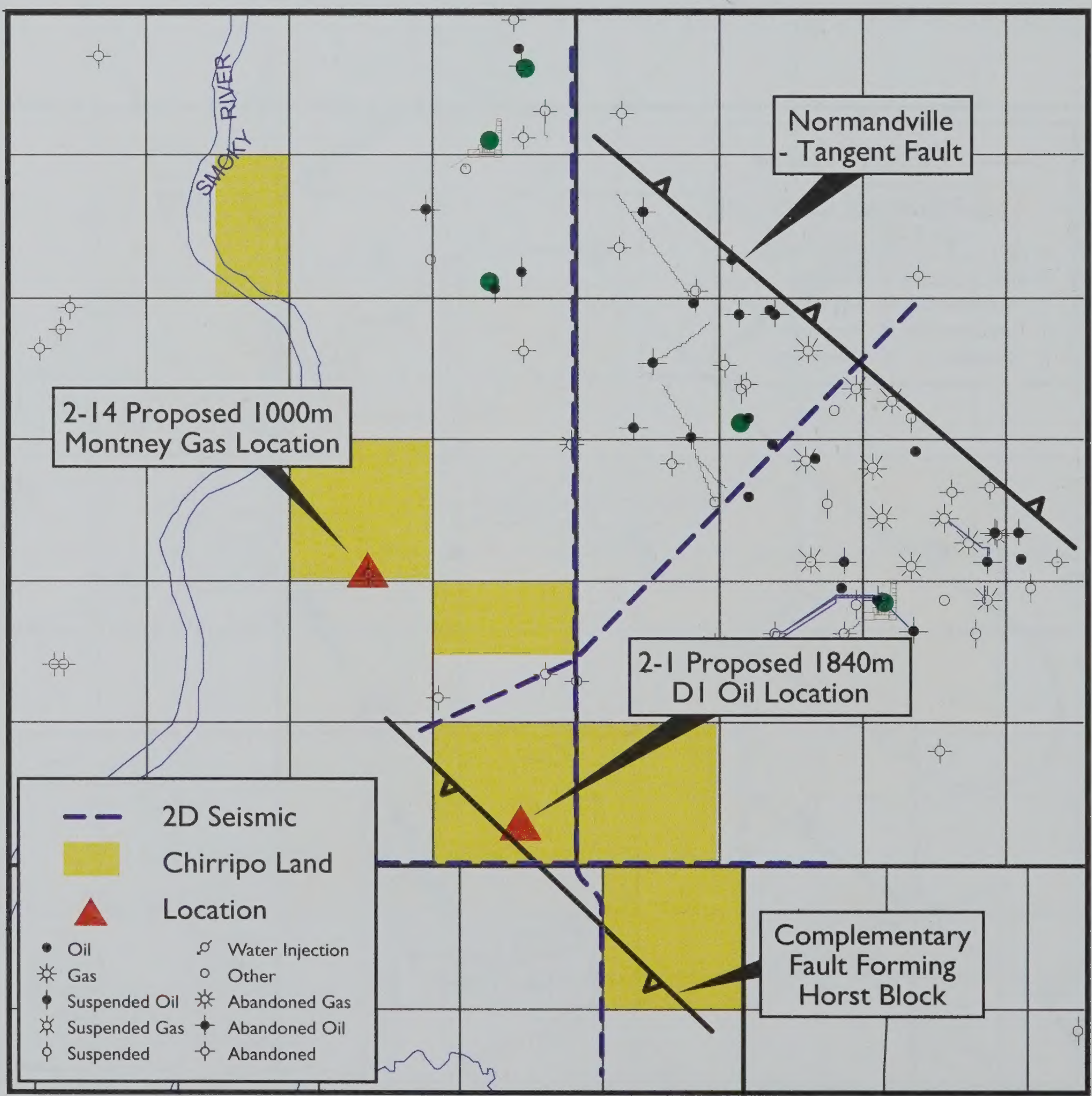
In the first quarter of 2003 Chirripo purchased a gas well producing 130 mcf/d net and three suspended wells in a Viking oil pool with a gas cap that had not been exploited. The 16-15 gas cap well which the Company has a 75% working interest, drill stem tested 1.0 mmcf/d from the Viking sand and has a third party evaluation of 0.8 bcf of recoverable reserves. The Company plans to frac and test the gas well in the third quarter of 2004. Chirripo also has a re-entry candidate at 14-12 for Gething production. The Gething standstone is composed of marine shoreline sands crosscut occasionally by younger channel sands. Should both wells prove economic, the wells will be tied-in to the CNRL gas gathering system in late fall with production commencing in the fourth quarter 2004. The Company has continued to consolidate its land position in this area through 2003 and now has six sections of land at an average working interest of 75%.



Peace River Arch - Exploration

Tangent Area, Alberta

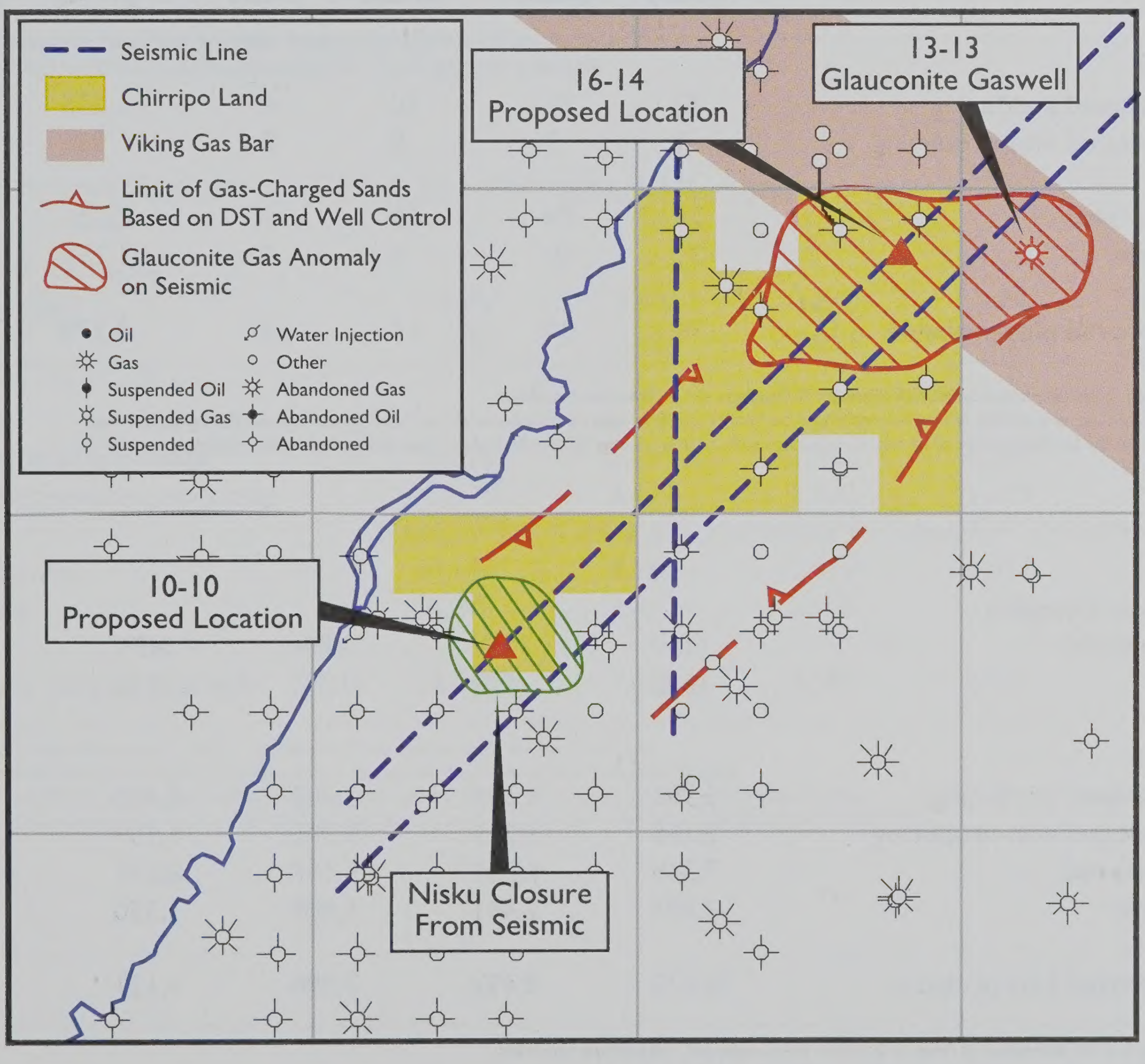
Chirripo has 5.5 sections of undeveloped land with a working interest of 100% in an area characterized by multi-zone potential, year round access and excess capacity at nearby processing infrastructure. The Company has acquired 15 miles of 2D seismic to further evaluate the hydrothermal dolimitization along the Normandville/Tangent Fault within the Wabamun formation and to a lesser extent, the channel sands prevalent in the Montney formation. The Company has two prospects being reviewed and plans to drill one well with partners prior to the end of 2004. Analagous Wabamun wells typically produce 100 bbls/d initially and recover 150 Mbbls of oil. Similarly, wells from the Montney formation typically produce 500 mcf/d and recover 0.75 Bcf of gas.



Plains - Exploration

Fenn Big Valley Area, Alberta

The Company has 100% working interest in 600 acres of undeveloped land located approximately 30 km south of Stettler. Proprietary seismic has clearly defined a Nisku attic oil trap in 10-10-35-20W4 in close proximity to the established Leduc reef (D2/D3) oil pools. In addition, the Company has a Glauconite sand prospect at 16-14-35-20W4 offsetting an existing Glauconite gas well in 13-13-35-20W4. Rather than spend the estimated $1.1 million to drill and test the two opportunities the Company decided to farm-out the prospects and retain overrides of 5-15% sliding scale on oil and 15% on gas. In November of 2003, the Company signed a seismic option agreement with a strong joint venture partner. Following the results of their 2D and 3D seismic program over the winter, the farmee has licensed a Leduc well in section 10 with an anticipated spud date of May 2004.



Operations Review

Reserves

The January 1, 2004 Paddock Lindstrom & Associates reserve report was prepared utilizing the methodology and definitions as set out under National Instrument 51-101 ("NI 51-101"). The change to proved and probable reserve definitions implemented by NI 51-101 for the year ended December 31, 2003 make reserve quantity and value comparisions to prior years difficult. The resulting values of total proved plus 50% risked probable (established) reserves determined in 2002 and prior years are compared to the total proved plus probable reserves calculated under NI 51-101. The reserve data provided in this annual report represents only a portion of the disclosure required under NI 51-101. Additional disclosure will be provided by the Company's NI 51-101 filing with the Alberta Securities Commission.

Reserves - Forecast Prices and Costs

Reserves Category	Light Oil		Natural Gas Liquids		Natural Gas	
	Gross *(Mbbl)*	Net *(Mbbl)*	Gross *(Mbbl)*	Net *(Mbbl)*	Gross *(MMcf)*	Net *(MMcf)*
Proved						
Developed producing	73	71	10	9	1,235	1,201
Developed non-producing	2	3	0	0	986	783
Total proved	75	74	10	9	2,221	1,984
Probable	21	20	6	5	1,158	1,006
Total proved plus probable	96	94	16	14	3,379	2,990

As at January 1, 2004 determined by Paddock Lindstrom & Associates Ltd., independent consultants.
Gross reserves include only working interest reserves. Under NI 51-101 royalty interest reserves owned by the Company are excluded from gross reserves.
Net reserves are the Company's share of all reserves including royalty interest reserves after deduction for crown, freehold and other royalties.

Net Present Value - Forecast Prices and Costs

Reserves Category *($ thousands)*	NPV *(0%)*	NPV *(5%)*	NPV *(10%)*	NPV *(15%)*	NPV *(20%)*
Proved					
Developed producing	5,201	4,334	3,792	3,413	3,128
Developed non-producing	2,168	1,717	1,395	1,157	977
Total proved	7,369	6,051	5,187	4,571	4,105
Probable	3,304	2,441	1,909	1,550	1,295
Total proved plus probable	10,673	8,492	7,096	6,121	5,400

As at January 1, 2004 determined by Paddock Lindstrom & Associates Ltd., independent consultants.
Discounted data represents the present value of estimated future cash flow before income taxes including ARTC.
As required by NI 51-101, undiscounted well abandonment costs of $0.2 million are included in the net present value calculation.

Forecast Prices

	WTI@ Cushing	Edmonton Reference	Henry Hub	AECO "C"	Alberta Spot
	$US/bbl	*$Cdn/bbl*	*$US/mmbtu*	*$Cdn/mmbtu*	*$Cdn/mmbtu*
2004	29.00	37.61	5.25	6.00	5.82
2005	26.50	34.25	4.75	5.31	5.13
2006	25.50	32.90	4.40	4.83	4.64
2007	25.00	32.21	4.45	4.87	4.68
2008	25.50	32.85	4.50	4.92	4.73
2009	26.01	33.51	4.55	4.96	4.77
2010	26.53	34.18	4.60	5.01	4.81
2011	27.06	34.86	4.65	5.05	4.85
2012	27.60	35.56	4.74	5.15	4.94
2013	28.15	36.27	4.84	5.26	5.04

All costs are escalated at 2% per year from 2004. All prices are escalated at 2% per year after 2018.
A Cdn/US exchange rate of $0.75 was assumed constant for all years presented in this table.

Net Present Value – Constant Prices and Costs

Reserves Category *($ thousands)*	NPV *(0%)*	NPV *(5%)*	NPV *(10%)*	NPV *(15%)*	NPV *(20%)*
Proved					
Developed producing	6,975	5,709	4,928	4,382	3,973
Developed non-producing	3,174	2,472	1,982	1,629	1,364
Total proved	10,149	8,181	6,910	6,011	5,336
Probable	4,741	3,457	2,675	2,154	1,786
Total proved plus probable	14,890	11,638	9,585	8,165	7,122

As at January 1, 2004 determined by Paddock Lindstrom & Associates Ltd., independent consultants.
Discounted data represents the present value of estimated future cash flow before income taxes including ARTC.
As required by NI 51-101, undiscounted well abandonment costs of $0.2 million are included in the net present value calculation.
The constant case assumes prices of Cdn $40.92/bbl for Edmonton reference price for light sweet oil and Cdn $6.08/mcf for AECO "C".

Gross Reserves Reconciliation

	Proved			Proved + Probable		
	Crude Oil & Ngl's *(Mstb)*	Natural Gas *(MMcf)*	Total *(Mboe)*	Crude Oil & Ngl's *(Mstb)*	Natural Gas *(MMcf)*	Total *(Mboe)*
January 1, 2003	112	2,281	492	130	2,506	547
Acquisitions	9	349	67	10	998	176
Additions	10	0	10	16	0	16
Revisions	(26)	(95)	(42)	(24)	189	8
Production	(20)	(314)	(72)	(20)	(314)	(72)
January 1, 2004	85	2,221	455	112	3,379	675

As at January 1, 2004 determined by Paddock Lindstrom & Associates Ltd., independent consultants.
Gross reserves are based on escalated price and cost assumptions.
Gross reserves include only working interest reserves. Under NI 51-101 royalty interest reserves owned by the Company are excluded from gross reserves.

Net Asset Value

The following net asset value calculations, effective December 31, 2003, are based on reserve values from the Paddock Report and include an internally generated estimate by management for undeveloped land of $110/acre. The fully diluted calculation includes 750,500 options exercisable at an average price of $0.47 per share. The commodity prices that were used in the 2003 evaluation can be found on page 9.

($ thousands, except per share amounts)	10%	15%
Established reserves pre-tax including ARTC discounted at [1]	7,096	6,121
Undeveloped land	2,994	2,994
Working capital deficit	(1,021)	(1,021)
Bank loans	(975)	(975)
Net asset value	8,094	7,119
Per share amounts [2]		
Basic	0.96	0.84
Fully diluted	0.88	0.77

(1) Proven plus probable reserves as defined by NI 51-101 based on escalated price and cost assumptions.
(2) Basic shares issued & outstanding at Dec.31, 2003 – 8,461,668; fully diluted shares issued and outstanding at Dec. 31, 2003 – 9,212,168.
(3) Proven plus probable reserves risked at 50% pre-tax including ARTC discounted at 10% based on escalated price and cost assumptions.

Using a 10% discount factor, the fully diluted net asset per share increased 9% from $0.81[3] per share at year-end 2002 to $0.88 per share at year-end 2003. This slight improvement resulted from an increase in the Company's established reserves and a larger inventory of undeveloped land offset by a higher working capital deficit at the end of 2003.

Finding, Development and Acquisition (FD&A) Costs

Finding, development and acquisition costs are one measure of a company's ability to add reserves cost-effectively. The FD&A cost figure is arrived at by dividing total capital expenditures incurred during the period by the reserve additions for the same period. The additions included reserves added through drilling, exploitation and acquisitions. A multi-period FD&A calculation is typically used to judge performance because of the length of time to implement a full-cycle exploration program. Due to reserve definitions implemented by NI 51-101, total proved plus 50% risked probable (established) reserves accumulated to 2002 have been added to 2003 total proved plus probable reserves calculated under 51-101 for the three year period from 2001 to 2003.

($ thousands, except where noted)	2003	2003-2001
Total capital	2,044	4,977
Future capital	-	244
Total finding, development and acquisition costs	2,044	5,221
Reserve additions		
Proved *(Mboe)*	77	478
Proved plus probable *(Mboe)*	192	653
Reserve additions based on forecast price and cost assumptions.		
Costs per boe		
Proved *($/Boe)*	26.55	10.92
Proved plus probable *($/Boe)*	10.65	8.00

Recycle Ratio

The recycle ratio effectively compares the cash generated by each boe produced to the cost of replacing each boe. It is arrived at by dividing the Company's average field netback during the period by its FD&A cost for the same period. In 2003 Chirripo achieved a recycle ratio of 0.8 times on a proved basis and 2.1 times on a proved plus probable basis utilizing the 2003 field netback of $22.03 per boe.

Land Holdings

The following table discloses the Company's developed and undeveloped land holdings in acres as well as the net interest of Chirripo as at December 31, 2002 and 2003:

	Developed		Undeveloped		Total	
	Gross	Net	Gross	Net	Gross	Net
2002	27,103	7,464	44,567	19,833	71,670	27,297
2003						
Keg River Basins	1,920	465	5,280	4,649	7,200	5,114
Peace River Arch	14,183	4,750	24,374	14,005	38,557	18,755
Central Plains	10,177	797	10,887	4,058	21,064	4,855
Other	6,933	647	16,052	4,510	22,985	5,157
Total	33,213	6,659	56,593	27,222	89,806	33,881

"Gross" means the total number of acres in which the Company has an interest.
"Net" refers to the aggregate of the percentage interests of the Company in the gross acres.

Management's Discussion & Analysis

The following discussion and analysis of operational results and financial condition should be read in conjunction with the Company's audited financial statements and notes thereto for the years ended December 31, 2003 and 2002. Where amounts are expressed on a barrel of oil equivalent basis (boe), gas volumes have been converted to barrels of oil at six thousand cubic feet per barrel (6:1). References to oil in this discussion include crude oil and natural gas liquids (NGLs). NGLs include condensate, butane and propane. This discussion contains certain forward-looking statements for 2004 that are based on assumptions about future events and are subject to risks and uncertainties that may cause actual results to vary materially from these statements.

Chirripo is pleased to report the following financial highlights of 2003 compared to 2002:

- Increase of 268% in cash flow from operations to $1,178,945
- Increase of 109% in total revenue to $3,133,655
- Increase of 93% in net capital expenditures to $2,043,699
- Increase of 56% in average daily production to 226 boe/d

Operating Margin Analysis

($/boe)	2003	2002
Petroleum and natural gas sales	38.01	28.27
Royalty expense net of ARTC	6.96	4.80
Operating costs	9.02	9.13
Field netback	22.03	14.34
General and administrative	5.77	6.82
Interest expense net of other income	0.80	1.48
Current income taxes	1.16	-
Cash flow from operations	14.30	6.04
Depletion and depreciation	7.50	7.21
Stock based compensation	0.07	-
Future site restoration	1.63	0.40
Future income taxes	0.88	1.10
Net earnings (loss)	4.22	(2.67)

Sales Volumes

	2003	2002
Natural gas (mcf/d)	981	602
Oil and NGLs (bbls/d)	62	45
Total (boe/d)	226	145

Production averaged 226 boe per day in 2003, an increase of 56% from 145 boe per day in 2002. Natural gas sales increased 63%, on a year-over-year basis, to 981 mcf per day in 2003. Oil and NGL sales increased 38% from 45 bbls per day in 2002 to 62 bbls per day in 2003. A first quarter 2003 acquisition at High Prairie, a recompletion at Shekilie, a gas conservation scheme installed at Spirit River and a full year's impact of a well drilled in the fourth quarter 2002 at Gordondale contributed to increased gas sales in 2003. Similarly, a recompletion at Bear Canyon, a reactivation at Amigo and a fourth quarter 2003 acquisition at Amigo improved oil and NGL sales in 2003. Chirripo's business plan for 2004 has two drilling projects and one re-entry planned for the winter capital program before break up occurs in early April. Chirripo expects to add new production in the second and third quarter of 2004 following the completion of these winter projects.

Selling Prices

	2003	2002
Natural gas ($/mcf)	6.31	4.20
Oil ($/bbl)	39.12	37.08
Natural gas liquids ($/bbl)	33.47	25.68
Total ($/boe)	38.01	28.27

Production Revenue

($ 000's)	2003	2002
Natural gas	2,259	922
Oil	783	506
Natural gas liquids	92	73
Total	3,134	1,501

Total revenue increased 109% to $3,133,655 in 2003 from $1,501,079 for the comparative period in 2002. Natural gas revenues for 2003 rose 145% from last year's level of $921,876 accounting for 82% of the increase in total revenues. Stronger gas prices provided 35% of the gas revenue increase while production gains supplied the remaining 65%. Oil and natural gas liquid revenues for 2003 increased 51% over 2002 due to a 10% increase in prices and a 38% increase in volumes.

Royalty Expense

($ 000's)	2003	2002
Crown	559	260
Overriding	37	9
Alberta royalty tax credit	(22)	(14)
Total	574	255

Royalties as a percentage of working interest sales revenue increased to 19.2% in 2003 from 18.1% in 2002. On an equivalent unit basis, royalties averaged $6.96 per boe in 2003 compared to $4.80 per boe in 2002. The overall increase in royalty expense was primarily caused by higher total revenues and as well, a relative increase in crown royalty rates due to higher commodity prices.

Operating Expense

Operating expenses increased 54% to $743,905 in 2003 from $484,529 in 2002 due entirely to the year-over-year increase in production volumes of 56%. On a per unit basis, operating expenses declined slightly from $9.13 per boe in 2002 to $9.02 per boe in 2003. Chirripo's higher than industry average unit operating expenses reflects third-party costs such as contract operator, gathering, processing and compression costs that will be incurred until such time as Chirripo operates more of its own facilities.

General and Administrative Expenses

Total general and administrative expenses increased 31% from $362,217 in 2002 to $474,626 in 2003. The increased costs resulted from additional personnel and related office space and engineering and geophysical support required to manage Chirripo's growing capital expenditure program and production base. On a per boe basis, the rate dropped 18% from $6.82 per boe in 2002 to $5.77 per boe in 2003 directly as a result of economies of scale achieved through higher production levels. As the Company's daily production rate is expected to increase in 2004, economies of scale should continue to drive Chirripo's per unit general and administrative costs downward.

Financing Charges

Interest expense decreased 9% from $80,455 in 2002 to $73,600 in 2003. Lower interest rates combined with a decrease in bank commitment fees offset slightly higher average debt levels. On an equivalent unit basis, interest expense net of other income for 2003 decreased 46% due to an increase in daily production rates and interest income earned on security deposits held by the Alberta Energy and Utilities Board (EUB) related to the Company's Licensee Liability Rating (LLR) on operated wells.

Depletion and Site Restoration

Depletion expense increased 54% from $382,491 in 2002 to $617,438 in 2003. 91% of the increase in depletion expense was due to production increases in 2003 and the remaining 9% was due to an increase in depletion rate from $7.22 per boe in 2002 to $7.50 per boe in 2003 reflecting the higher cost of new reserves added in 2003. The Company's site restoration expense for 2003 increased five-fold to $134,742 ($1.63 per boe) in 2003 from $21,466 ($0.40 per boe) in 2002. Included in the 2003 site restoration charge is a catch up provision of $64,137 ($0.78 per boe) for restoration costs associated with the Company's accelerated abandonment program to reduce the Company's LLR ratio with the EUB. The EUB has fully refunded $278,180 in security deposits by the end of the third quarter 2003 (see Note 3 to the financial statements). The remaining increase in the site restoration unit rate of $0.45 per boe relates to higher average abandonment estimates per well and the acquisition of five operated suspended wells in 2003.

Income Taxes

The following table describes Chirripo's future tax pools at December 31:

($ 000's)	2003	2002
Canadian oil and gas property expense	1,604	1,193
Canadian development expense	625	120
Undepreciated capital cost	544	376
Non-capital losses	-	22
Other	-	7
Total	2,772	1,718

The provision for income taxes increased significantly to $168,950 in 2003 from $58,260 in 2002, due to the more than five-fold increase in 2003 earnings before taxes. The Company incurred a current tax expense of $96,000 as the 2003 capital program shielded a portion of Chirripo's earnings from tax, effectively reducing the current rate to 18.6% from the statutory combined rate of 40.8%. At December 31, 2003, Chirripo had cumulative tax pools of $2,772,000 available to reduce future taxable income.

Earnings and Cash Flow from Operations

Cash flow from operations increased 268% to $1,178,945 in 2003 from $320,471 in 2002. Significantly higher revenues due to increased commodity prices and daily production rates offset related increases in cash expenses. Cash flow per diluted share was $0.14, an increase of 185% over the $0.05 per diluted share recorded in 2002. The per share increase was less than the absolute increase as a result of shares issued in 2003. Higher cash flow from operations offset increased non-cash expenses enabling Chirripo's net earnings of $348,215 ($0.04 per basic share) in 2003 to increase substantially over a 2002 net loss of $141,746 ($0.02 per basic share).

Capital Expenditures

($ 000's)	2003	2002
Land and seismic	565	96
Drilling and completions	770	399
Production equipment	175	146
Property acquisitions	562	470
Office	13	2
Total capital expenditures	2,085	1,113
Dispositions	(41)	(147)
Net capital expenditures	2,044	966

Chirripo increased the net capital spending program by 112% to $2,043,699 in 2003 from $965,954 in 2002 of which $277,291 represented capital costs incurred in 2003 but paid for in 2004 (2002 – $50,200). The Company successfully participated in 8 (2.6 net) oil wells and 1 (0.3 net) gas wells, acquired a total of 9,200 net undeveloped acres and added one new area of focus at Giroux Lake. In addition, the Company strategically acquired 39 miles of 2D and 10 square miles of 3D seismic to upgrade 2004/2005 drilling prospects in five core properties.

Liquidity and Capital Resources

($ 000's)	2003	2002
Cash flow from operations	1,180	320
Proceeds from common shares issued	35	728
Decrease in bank debt	(145)	(80)
Decrease (increase) in working capital	974	(2)
Total	2,044	966

Chirripo's 2003 capital expenditure program was funded by 58% cash flow from operations (2002 – 31%), 2% from new equity (2002 – 69%) and the remainder was funded from a decrease in working capital. Proceeds from new equity issued in 2003 resulted entirely from the exercise of options. A total of $727,500 was raised in 2002 from the issuance of 1.9 million shares at an average price of $0.38 per share. On January 29, 2004 Chirripo closed a brokered private placement for gross proceeds of $1,050,000 to help finance the Company's winter capital program (see note 15 to the financial statements). Chirripo's revolving operating demand loan provides for a line of credit of $1.8 million of which $825,000 remained unused at year-end. In addition to the operating line, the Company has a non-revolving acquisition demand loan of $1.5 million that is currently unused. On March 31, 2004 Chirripo had 9,976,668 common shares issued and outstanding, 750,000 common share purchase warrants exercisable at $0.85 per share and 735,500 stock options with a weighted average exercise price of $0.47 per share.

Business Risks

The business of exploring for, developing and producing oil and natural gas reserves involves substantial financial, operational and regulatory risk that have the potential to significantly affect Chirripo's results.

Operationally, there is substantial exploration risk related to the human and capital resources allocated to find oil and natural gas reserves in economic quantities. Selling profitable reserves may be delayed for long periods of time due to processing constraints through third party plants or lack of transportation capacity through third party gathering systems. Forecast production from oil and natural gas reservoirs may decline more quickly than anticipated, resulting in lower cash flow and lower reserve recovery. Chirripo competes directly for petroleum and natural gas leases and field services with entities that have greater technical and financial resources.

Financially, the price Chirripo receives for oil, natural gas and natural gas liquids fluctuates continuously and, for the most part, is beyond the Company's control. Chirripo's growth is partially dependent upon external sources of financing which may not be available on acceptable terms.

Chirripo's operations are subject to extensive environmental controls and regulations by various levels of government and there is risk that future changes in government policy could adversely impact Chirripo's profitabilty.

Chirripo mitigates these risks by hiring highly qualified personnel, focusing operational efforts in geographic areas with high-quality reservoirs where the Corporation has existing knowledge and expertise, access to third party facilities and when appropriate, undertakes a certain portion of its activities jointly with industry partners. Chirripo is currently selling its products through daily spot contracts with 30-day termination notices. As the Corporation's production base increases, Chirripo intends to consider a price risk management program.

Corporate Outlook

Chirripo's land acquisition and seismic program in 2003 provided a strong platform to contribute significantly to the Corporation's inventory of drilling prospects in 2004 and 2005. Chirripo has budgeted a $2.8 million capital expenditure program for 2004 that will be funded by the net proceeds of the January 29, 2004 equity financing, cash flow from operations and an operating line of $1.8 million of which $1.0 million had been drawn at December 31, 2003. Additional funds are available to acquire producing properties by utilizing Chirripo's acquisition line of $1.5 million which was undrawn at December 31, 2003.

Management's Report

To the Shareholders of Chirripo Resources Inc.:

The accompanying financial statements and all operational and financial information in this annual report are the responsibility of management. The financial statements have been prepared in accordance with Canadian generally accepted accounting principles. Management is satisfied that the financial information throughout the balance of this annual report is consistent with the information presented in the financial statements.

Management is also responsible for maintaining a system of internal control designed to provide reasonable assurance that assets are safeguarded and that the accounting system provides timely, accurate and reliable financial information.

Meyers Norris Penny LLP, the independent auditors appointed by the shareholders, have examined the financial statements of the Company for the year ended December 31, 2003. The Audit Committee has reviewed these statements with management and the auditors. The Board of Directors has approved the financial statements of the Company on the recommendation of the Audit Committee.

Issa Abu-Zahra
President and Chief Executive Officer
March 24, 2004

David Dakers
Secretary and Chief Financial Officer

Auditors' Report

To the Shareholders of Chirripo Resources Inc.:

We have audited the balance sheets of Chirripo Resources Inc. as at December 31, 2003 and 2002 and the statements of operations and retained earnings and cash flows for the years then ended. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these financial statements present fairly, in all material respects, the financial position of the Company as at December 31, 2003 and 2002 and the results of its operations and cash flows for the years then ended in accordance with Canadian generally accepted accounting principles.

Meyers Norris Penny LLP

Chartered Accountants
Calgary, Alberta
February 27, 2004

Balance Sheets

As at December 31

	2003	2002
Assets		
Current		
Cash	15,968	5,826
Accounts receivable	234,186	267,081
ARTC receivable	22,008	15,425
Prepaid expenses and deposits (Note 3)	24,826	257,044
	296,988	545,376
Property and equipment (Note 4)	4,304,295	2,869,950
	4,601,283	3,415,326
Liabilities		
Current		
Accounts payable and accruals	1,222,148	507,872
Bank loans (Note 5)	975,000	1,120,000
Income taxes payable (Note 6)	96,000	-
	2,293,148	1,627,872
Future income taxes (Note 6)	536,950	464,000
Future site restoration	85,229	26,614
	2,915,327	2,118,486
Shareholders' Equity		
Share capital (Note 7)	1,080,040	1,044,740
Contributed surplus (Note 8)	5,600	-
Retained earnings	600,316	252,100
	1,685,956	1,296,840
	4,601,283	3,415,326

Approved on behalf of the Board:

William R. Miller - Director

M. A. Williams

Michael A. Williams - Director

Statements of Operations and Retained Earnings

For the years ended December 31

	2003	2002
Revenue		
Petroleum and natural gas sales	2,983,675	1,401,810
Royalty income	149,980	99,269
Royalty expense net of ARTC	(574,074)	(255,040)
	2,559,581	1,246,039
Expenses		
Operating	743,905	484,529
General and administrative	474,626	362,217
Interest and bank charges	73,600	80,455
Future site restoration	134,742	21,466
Depletion and amortization	617,438	382,491
Stock-based compensation (Note 8)	5,600	-
	2,049,911	1,331,158
Earnings (loss) from operations	509,670	(85,119)
Other income	7,496	1,633
Earnings (loss) before income taxes	517,166	(83,486)
Income taxes (Note 6)		
Current	96,000	-
Future	72,950	58,260
	168,950	58,260
Net earnings (loss)	348,216	(141,746)
Retained earnings, beginning of year	252,100	393,846
Retained earnings, end of year	600,316	252,100
Earnings (loss) per share (Note 9)		
Basic	0.042	(0.022)
Diluted	0.041	-

Statements of Cash Flows

For the years ended December 31

	2003	2002
Cash provided by (used for) the following activities		
Operating		
Net earnings (loss)	348,216	(141,746)
Add items not involving a current cash outlay		
Depletion and amortization	617,438	382,491
Future site restoration	134,742	21,466
Stock-based compensation (Note 8)	5,600	-
Future income taxes (Note 6)	72,950	58,260
	1,178,946	320,471
Changes in non-cash working capital balances related to operations (Note 14)	791,514	(47,341)
	1,970,460	273,130
Financing		
Repayment of employee loan	-	38,592
Bank loan repayments, net	(145,000)	(80,000)
Issuance of shares	35,300	727,500
	(109,700)	686,092
Investing		
Changes in non-cash working capital balances related to investing (Note 14)	277,291	50,200
Purchase of property and equipment	(2,092,799)	(1,112,843)
Proceeds on disposal of property and equipment	41,017	146,889
Payment of site restoration costs	(76,127)	(42,078)
	(1,850,618)	(957,832)
Increase in cash	10,142	1,390
Cash, beginning of year	5,826	4,436
Cash, end of year	15,968	5,826
Supplemental cash flow information		
Interest paid	67,847	73,554
Income tax paid	-	-

1. Nature of Business

Chirripo Resources Inc. ("the Company") is incorporated under the laws of Alberta and its principal activity is the exploration for and development of oil and gas properties in Western Canada.

2. Accounting Policies

These financial statements have been prepared in accordance with Canadian generally accepted accounting principles. In preparing these financial statements, management is required to make estimates and assumptions. In management's opinion, the financial statements have been properly prepared using careful judgment within reasonable limits of materiality and within the framework of the accounting policies summarized below:

The Company follows the full cost method of accounting for petroleum and natural gas properties, whereby all costs associated with the exploration for, and the development of, petroleum and natural gas reserves, whether productive or unproductive, are capitalized in cost centres. Costs capitalized include land acquisition costs, geological and geophysical expenditures, rentals on undeveloped properties and drilling and overhead expenses related to exploration and development activities. Proceeds from disposition of property sales are credited to the net book value of the property and equipment. Gains and losses are not recognized upon disposition of oil and gas properties other than equipment, unless the disposition would significantly alter the rate of depletion.

Costs capitalized are depleted and amortized using the unit-of-production method based on gross proved oil and gas reserves as determined by independent engineers. For purposes of the depletion calculation, proved oil and gas reserves are converted to a common unit of measure on the basis of the relative energy content of 6,000 cubic feet of natural gas per barrel of oil.

In applying the full cost method, the Company performs a ceiling test which restricts the capitalized costs less accumulated depletion, future income taxes and the site restoration provision from exceeding an amount equal to the estimated undiscounted value of future net revenues from proved oil and gas reserves, based on current prices and costs, and after deducting estimated future site restoration costs, general and administrative expenses, financing costs and income taxes. Any costs carried on the balance sheet in excess of the ceiling test limit are charged to income as additional depletion.

Property and equipment, other than petroleum and natural gas properties, are stated at cost less amortization calculated using the straight-line basis at the following annual rates:

Furniture and fixtures	20%
Computer equipment	30%

2. Accounting Policies (continued)

Joint venture activities

Substantially all of the Company's petroleum and natural gas exploration and production activities are conducted jointly with others. Accordingly, these financial statements reflect only the Company's proportionate interest in such activities.

Bank loans

Commencing in 2002, the Company retroactively adopted the pronouncement of the Canadian Institute of Chartered Accountants ("CICA") concerning the "Balance Sheet Presentation of Callable Debt Obligations Expected to be Refinanced". Since both of the Company's credit facilities are subject to an annual renewal the new accounting standard requires that the loans be presented as a current liability (Note 5).

Future site restoration costs

The Company provides for site restoration and abandonment costs over the life of the proved reserves on a unit-of-production basis. Costs are estimated each year by management based on current regulations, costs, and technology and industry standards. The annual charge to income is recorded as a provision for future site restoration costs and the accumulated liability is classified as a long-term liability. Actual costs, as incurred, are charged to the accumulated liability.

Income taxes

The Company utilizes the asset and liability method of accounting for income taxes. Under this method, future income tax liabilities and assets are recognized for the estimated tax consequences attributable to differences between the amounts reported in the financial statements and their respective tax bases using tax rates that are expected to be in effect when the related income and expense items are expected to be realized. The effect of a change in income tax rates on future income tax liabilities and assets is recognized in income in the period that the change occurs. In addition, the future benefits of income tax assets, including unused tax losses are recognized, subject to a valuation allowance, to the extent that it is more likely than not that such future benefits will ultimately be realized.

Flow-through shares

Income tax legislation permits the flow through to shareholders of income tax deductions relating to certain qualified resource expenditures. The income tax benefits renounced are reflected as a future income tax liability and deducted from share capital.

2. Accounting Policies (continued)

Per share amounts

Basic earnings per share are calculated using the weighted average number of shares outstanding during the year. Diluted earnings per share are calculated based on the treasury stock method which assumes that any proceeds obtained on the exercise of options and warrants would be used to purchase common shares at the average price during the period.

Stock-based compensation

In November 2003, the CICA revised Handbook Section 3870, Stock-based Compensation and other Stock-based Payments, with respect to the accounting for stock-based compensation and other stock-based payments. The revised recommendations require that beginning January 1, 2004, the fair value-based method be used to account for all transactions whereby goods and services are received in exchange for stock-based compensation and other stock-based payments. Under the fair value-based method, compensation costs are measured at fair value at the date of grant and are expensed over the award's vesting periods.

In accordance with one of the transitional options permitted under Section 3870, the Company has elected to early adopt the new recommendations effective January 1, 2003 and prospectively apply the standard for employee stock awards granted after January 1, 2003. Prior to the adoption of the fair value-based method, the Company, as permitted by Section 3870, had chosen to continue its existing policy of recording no compensation cost on the grant of stock options to employees.

As required by the transitional provisions, proforma net income and earnings per share information has been provided as if the fair value method had been used for options granted between January 1, 2002 and December 31, 2002 (Note 8).

Measurement uncertainty

The preparation of financial statements in conformity with Canadian generally accepted accounting principles requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Accounts receivable are stated after evaluation as to their collectibility and an appropriate allowance for doubtful accounts is provided where considered necessary. The amounts recorded for depletion of property and equipment and the provisions for future abandonment and site restoration costs are based on estimates. The ceiling test is based on such factors as estimated proven reserves, production rates, oil and natural gas prices, future costs and other relevant assumptions. By their nature, these estimates are subject to measurement uncertainty and the impact on the financial statements of future periods could be material if actual results differ from these estimates.

3. Prepaid Expenses and Deposits

The Company is required to pay a security deposit to the Alberta Energy and Utilities Board (EUB) related to the Company's Licensee Liability Rating (LLR) on operated wells. The EUB reassess the Company's LLR ratio on a monthly basis. Due to the Company's successful efforts in reactivating its operated wells, during 2003 the EUB has refunded the entire 2002 security deposit of $227,003.

4. Property and Equipment

2003	Cost	Accumulated Depletion and Depreciation	Net Book Value
Petroleum and natural gas properties	5,712,331	1,424,244	4,288,087
Furniture and fixtures	13,752	10,546	3,206
Computer equipment	25,589	12,587	13,002
	5,751,672	1,447,377	4,304,295

2002	Cost	Accumulated Depletion and Depreciation	Net Book Value
Petroleum and natural gas properties	3,673,991	813,828	2,860,163
Furniture and fixtures	13,752	7,616	6,136
Computer equipment	12,146	8,495	3,651
	3,699,889	829,939	2,869,950

The 2003 ceiling test was performed using wellhead prices of $38.65/bbl (2002 - $40.96/bbl) for oil and $5.87/mcf (2002 – $5.39/mcf) for natural gas. Based on these parameters, there is no impairment in the carrying value. During the current twelve month period, the Company capitalized $70,675 (2002 - $35,429) of general and administrative expenses related to exploration activities. Included in accounts payable and accruals is $277,291 (2002 - $50,200) of property and equipment purchases.

5. Bank Loans

	2003	2002
Revolving non-reducing operating demand loan (a)	975,000	950,000
Non-revolving acquisition demand loan (b)	-	170,000
	975,000	1,120,000

(a) Under the revolving non-reducing operating demand loan, the amount available is $1,800,000 which revolves by increments of $25,000. Amounts drawn down under the facility bear interest at the bank's prime rate plus 1% and there is a standby fee of 1/8 of one percent on undrawn amounts.

(b) Under the non-revolving acquisition demand loan amounts up to $1,500,000 may be borrowed. Amounts drawn down under the facility bear interest at the bank's prime rate plus 1 1/4% and there is a standby fee of 1/8 of one percent on undrawn amounts.

The loans are secured by a demand promissory note, a general assignment of book debts and a floating debenture in the amount of $5,000,000.

The terms of the banking agreement require that certain affirmative covenants be met. As at December 31, 2003, the Company was in violation of the covenant related to working capital. It is management's opinion that the Company has satisfied the working capital covenant from proceeds received on January 29, 2004 following the close of the Company's private placement (Note 15).

6. Income Taxes

At December 31, 2003, the Company has approximately $2,772,000 (2002 - $1,690,000) of tax pools available. In 2002, the Company also had $6,650 in unclaimed share issuance costs. The benefit of these tax pools has been recognized in these financial statements.

The income tax expense differs from the amount that would be expected by applying the current tax rates for the following reasons:

	2003	2002
Earnings (loss) before taxes	517,165	(83,486)
Expected tax expense at 40.8% (2002 – 41.6%)	211,003	(34,747)
Tax effect of expenses not deductible for tax purposes:		
Stock-based compensation	2,284	-
Resource allowance deducted for income tax purposes	(150,536)	(51,718)
Alberta royalty tax credit	(35,898)	(5,838)
Crown royalties	197,310	106,556
Other	126	44,007
Impact of lower future tax rates	(55,339)	-
Provision for income taxes	168,950	58,260
Allocated to:		
Current	96,000	-
Future	72,950	58,260

The components of the net future income taxes liability are as follows:

	2003	2002
Future income tax liabilities		
Petroleum and natural gas properties	569,122	491,426
Future income tax assets		
Future site restoration	(31,978)	(11,190)
Share issue costs	-	(3,245)
Other	(194)	(12,991)
Net future income tax liability	536,950	464,000

7. Share Capital

Authorized

An unlimited number of common voting shares
An unlimited number of preferred shares

The preferred shares may be issued from time to time in one or more series, each series consisting of a number of preferred shares as determined by the Board of Directors of the Company who may also fix the designations, rights, privileges, restrictions and conditions attaching to each series of preferred shares. There are no preferred shares issued.

Issued

Common shares

	Number of shares	Amount
Balance at December 31, 2001	6,318,334	462,910
Issued on exercise of options	150,000	27,500
Issued on exercise of warrants (a)	833,334	250,000
Common shares (b)	250,000	100,000
Flow-through shares (net of tax effect of renouncements) (c)	700,000	204,330
Balance at December 31, 2002	8,251,668	1,044,740
Issued on exercise of options	210,000	35,300
Balance at December 31, 2003	8,461,668	1,080,040

(a) In connection with the December 2001 flow-through issue the Company issued 833,334 warrants to purchase common shares. The warrants were exercised at a price of $0.30 per share in December 2002 for proceeds of $250,000.

(b) In August 2002 the Company completed a private placement of 250,000 common shares at a price of $0.40 per share for proceeds of $100,000.

(c) Two private placements (August and December 2002) totalling 700,000 flow-through shares were completed at a price of $0.50 per share for proceeds of $350,000. The related renunciation for both transactions was made effective December 31, 2002. Approximately $150,200 of qualifying expenditures had been incurred at that time, the remainder was incurred prior to February 28, 2003.

7. Share Capital (continued)

Stock options

The Company has established a stock option plan whereby the Company may grant options to its directors, officers, employees and consultants for up to 10% of the issued and outstanding common shares of the Company. Options granted prior to December 31, 2002 vest and are exercisable immediately following the grant of the options. Options granted in 2003 vest evenly over a three-year period commencing a year from the date of grant and expire five years after the date of grant.

Stock option transactions were as follows:

	Options	Weighted Average Exercise Price
Balance at December 31, 2001	530,000	0.18
Options granted	137,500	0.30
Options exercised	(150,000)	0.18
Balance at December 31, 2002	517,500	0.21
Options granted	443,000	0.63
Options exercised	(210,000)	0.17
Balance at December 31, 2003 – outstanding	750,500	0.47
Balance at December 31, 2003 – exercisable	307,500	0.24

At December 31, 2003, the following stock options were outstanding:

Number of Stock Options	Date of Expiry	Exercise Price
65,000	January 14, 2005	$0.11
125,000	July 3, 2006	$0.25
117,500	September 3, 2007	$0.30
443,000	November 14, 2008	$0.63
750,500		

Escrow shares

As at December 31, 2003, the Company had no common shares held in escrow.

8. Stock-Based Compensation

The Company accounts for stock options granted to directors, officers, employees and consultants using the "fair value method", whereby compensation is recorded equal to the fair value of the option granted over the term of vesting. During the year, 443,000 options with an estimated fair value of $145,100 were granted and will be amortized over the vesting period of 36 months. Stock based compensation recognized during the year was $5,600, leaving an unamortized balance of $139,500. The fair value of options granted during 2003 was estimated at the date of grant using the Black-Scholes option pricing model with the following weighted average assumptions:

Risk free interest rate (%)	3.21%
Expected volatility (%)	70.00%
Expected life (years)	4
Expected dividend yield (%)	-

Had the fair value method been used since January 1, 2002, the Company's proforma net loss for 2002 would have been $181,146 or $0.028 per share - basic.

Option pricing models require the input of highly subjective assumptions including the expected price volatility. Changes in the subjective input assumptions can materially affect the fair value estimate, and therefore, the existing models do not necessarily provide a reliable measure of the fair value of the Company's stock options.

9. Per Share Amounts

The weighted average number of common shares outstanding during fiscal 2003 was 8,357,723 (2002 – 6,560,891) shares. The number of shares added to the weighted average number of common shares outstanding for the dilutive effect of options utilizing the treasury stock method was 165,577 (2002 – 154,333). The effect of options exercised under this method for the 2002 diluted loss per share was anti-dilutive and therefore not disclosed on the Statement of Operations and Retained Earnings.

10. Commitments

The Company has entered into an office rental lease expiring January 2007. The Company has the following minimum annual lease payments:

2004	68,190
2005	68,190
2006	68,190
2007	5,682

11. Related Party Transactions

During the year, the Company paid $57,500 (2002 - $58,679) for consulting services, all of which is capitalized (2002 - $35,429) as property and equipment to one director (2002 – two directors) of the Company. These transactions were in the normal course of business and have been measured at the exchange amount which is the amount established and agreed upon by the related parties.

12. Segmented Information

The Company operates primarily in the oil and gas industry in Western Canada and as such, is defined as having only one industry and geographic segment.

13. Financial Instruments

The Company, as part of its operations, carries a number of financial instruments. It is management's opinion that the Company is not exposed to significant interest rate risk (except on its bank loans), or currency risk arising from these financial instruments.

Fair value

At December 31, 2003, the estimated fair market value of cash, accounts receivable and accounts payable is equal to the book value due to the short-term nature of these accounts. The fair market value of the bank loans approximates their book value as the loans carry a floating rate of interest.

Credit risk

Virtually all of the Company's accounts receivable are with customers in the oil and gas industry and are subject to normal industry credit risks.

14. Changes in Non-Cash Working Capital Balances

	2003	2002
Changes in non-cash working capital balances		
Accounts receivable	32,895	(44,776)
Prepaid expenses and deposits	232,218	(240,425)
Accounts payable and accruals	714,275	286,973
Net taxes payable	89,417	1,087
	1,068,805	2,859
Allocated to:		
Operating activities	791,514	(47,341)
Investing activities	277,291	50,200
	1,068,805	2,859

15. Subsequent Event

On January 29, 2004 the Company closed a private placement of 1,500,000 units for total gross proceeds of $1,050,000. Each unit consisted of one common share and one half warrant. Each full warrant will entitle the holder to acquire one common share at an exercise price of $0.85 until December 15, 2004. The agent received a cash commission of $68,250 and agent's options entitling it to acquire 150,000 units at the issue price for a period of twelve months from the closing of the offering. Additional share issue costs associated with this financing were $34,598.

16. Comparative Figures

Certain of the prior year's figures have been reclassified to conform to the current year's presentation.

Corporate Information

Directors

Michael A. Williams
Chairman of the Board
Calgary, AB

William R. Miller
Calgary, AB

Larry Braun
Calgary, AB

Issa Abu-Zahra
Calgary, AB

Thomas R. Wilcock
Calgary, AB

Officers

Issa Abu-Zahra
President and Chief Executive Officer
Calgary, AB

Thomas R. Wilcock
Vice-President of Exploration
Calgary, AB

David A. Dakers
Secretary and Chief Financial Officer
Calgary, AB

Auditors

Meyers Norris Penny, LLP
Calgary, AB

Reserves Engineers

Paddock Lindstrom & Associates Ltd.
Calgary, AB

Legal Counsel

Gowling Lafleur Henderson LLP
Calgary, AB

Transfer Agent and Registrar

Computershare Trust Company of Canada
Calgary, AB

Bankers

National Bank of Canada
Calgary, AB

Stock Exchange

TSX Venture Exchange
Trading Symbol: CHO

Head Office

1440 – 530, 8th Avenue S.W.
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Abbreviations

bbls	barrels
mbbls	thousand barrels
bbls/d	barrels per day
mcf	thousand cubic feet
mmcf	million cubic feet
bcf	billion cubic feet
mcf/d	thousand cubic feet per day
NGLs	natural gas liquids
boe	barrels of oil equivalent
mboe	thousand barrels of oil equivalent
mstb	thousand stock tank barrels

Chirripo Resources Inc.

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